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Comparison of Resource and Energy Yield Assessment Procedures

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Summary
In 2011, the European Wind Energy Association arranged a Comparative Resource Assessment Procedures exercise, in which parties from the wind energy industry were invited to carry out wind speed and energy yield predictions for a case study wind farm with the aim to compare results of different industry standard models and approaches.

37 organisations from 16 countries submitted results before the deadline; representing consultants, developers, wind turbine manufacturers, electricity generator/utility, R&D/university, component manufacturers, and service providers. Three companies submitted results shortly after the deadline; these results are included here.

In the case study, three steps in the prediction process add little to the overall spread of the predictions: the vertical extrapolation (contributes about 0%), the flow modelling (6%) and the wake modelling (5%). This is not surprising considering the limited vertical extrapolation distance (10 m), the on-site meteorological mast and the rather simple wind farm layout.

Three steps add significantly to the overall spread of predictions: the long-term correlation (32%), the technical losses estimation (20%) and the uncertainty estimation (38%). Here, the contribution from the long-term correlation seems particularly high considering the fact that all participants had the exact same two data sets available for the task.

The paper summarises the main results of the comparison exercise only; the detailed analysis of the methods, models and procedures employed by the participants will be published elsewhere.

1 Introduction

In 2011, the European Wind Energy Association arranged a Comparative Resource Assessment Procedures exercise, in which parties from the wind energy industry were invited to carry out wind speed and energy yield predictions for a case study wind farm with the aim to compare results of different industry standard models and approaches.

37 organisations from 16 countries submitted results before the deadline: consultants (18), developers (7), wind turbine manufacturers (5), electricity generator/utility (3), R&D/university (2), component manufacturers (1), service providers (1). Three companies submitted results shortly after the deadline; these results are included here.

The present paper summarises the main results of the comparison exercise; the detailed analysis of the methods, models and procedures employed by the participants will be published elsewhere.

2 Case study wind farm

The case study wind farm is located about 35 km WSW of Glasgow, Scotland, and consists of fourteen 2-MW wind turbines with a hub height of 60 m and a rotor diameter of 80 m. The layout of the wind farm is irregular, see Figure 1.

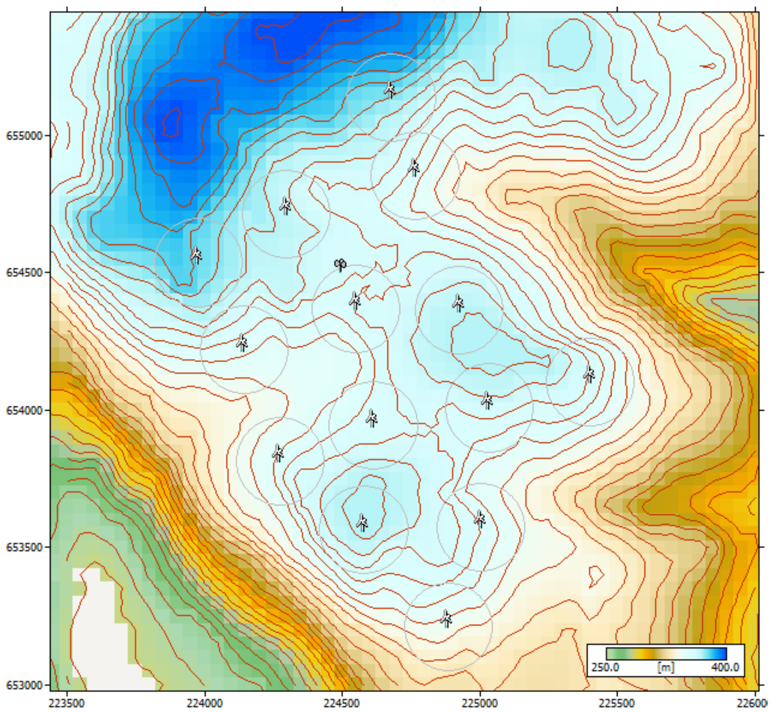

Figure 1. Layout and topographical setting of the case study wind farm. The circles around each wind turbine position correspond to four rotor diameters. The site assessment mast is shown with a cup anemometer icon. Height contour interval is 5 m.

The distances between neighbouring turbines are 3.7-4.8 rotor diameters. The grid coordinates of the site wind speed assessment mast location as well as of the wind turbines of the project layout were given in Ordnance Survey coordinate system.

The turbine type is described in the case study data pack as 'a typical variable-speed, pitch-regulated wind turbine'. The high wind speed cut-out is 25 ms^{-1} and re-cut-in wind speed is 20 ms^{-1}; both referred to 10-min averages of wind speed.

The operating characteristics of the wind turbines are specified by values of power output and thrust coefficient for every integer meter per second, in the interval between 3 ms^{-1} and 25 ms^{-1}. The air density is prescribed as 1.225 kgm^{-3} and constant over the wind farm site.

The case study data pack contains a brief description of the site electrical system to support any assumptions to estimate the electrical transmission loss factor: A 480V/33kV transformer is installed at the base of each turbine. The on-site cabling system collects the power produced at each turbine and connects to the site substation located close to turbine T1, where the point of metering is located.

Wind-climatological inputs

Several sets of wind data were supplied for estimation of the observed and predicted wind climates at the case study wind farm site. A 50-m meteorological mast on site measures 10-min wind speeds at 49.6 m and 35 m above ground level, standard deviations of wind speed at 49.6 m and 35 m and wind direction at 33.6 m a.g.l. The site mast coordinates have been modified from the real location to eliminate any commercial sensitivity of the data.

The site data cover a period of slightly more than 4 years, from 2002-09-17 to 2006-10-31. The recovery rate for a 4-y period from 2002-11 to 2006-10 is about 92%. A summary of this 4-y data series is given in Figure 2, as a 12-sector wind rose and the wind speed distribution.

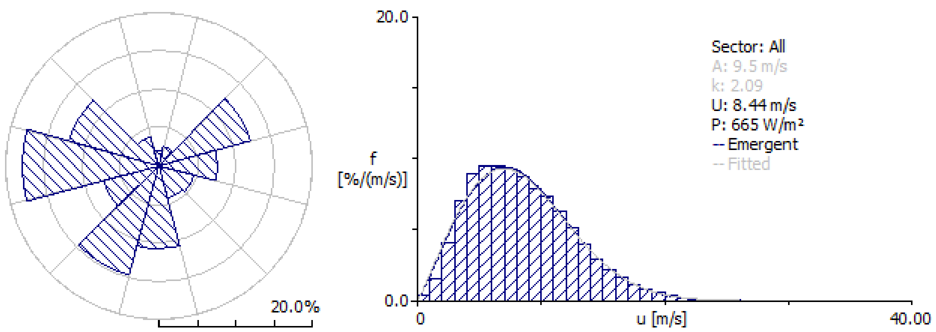

Figure 2. Wind rose and wind speed distribution for a 4-y period at the wind farm site mast.

The case study data pack describes these measurements in the following way: Wind speeds have been measured using Measnet-calibrated, high-quality, industry-standard anemometers with IEC standard compliant mounting arrangements. The data comes with calibration factors applied and directional data are relative to Ordnance Survey of GB Datum GB1936 (OS) grid north. The site-measured wind speeds have been multiplied with a small constant close to one to eliminate commercial sensitivity of the data.

In addition to the site mast, data from a reference station are also provided in the data pack. The exact location of the reference station is not given. Three data sets from this station are available: *i*) monthly mean wind speeds (in knots) from 1993-01 to 2007-01, *ii*) hourly values of wind speed (in knots) and direction (in degrees N) from 2002-09-01 to 2007-01-23, and *iii*) the observed wind climate representing the period 1993-01-01 to 2001-12-31 in 12 sectors (relative to true N) and 1-knot classes (starting at 0.5 knot) of wind speed.

A summary of a 4-y data series from 2002-11 to 2006-10 (from *ii* above) is given in Figure 3, as a 12-sector wind rose and the corresponding wind speed distribution.

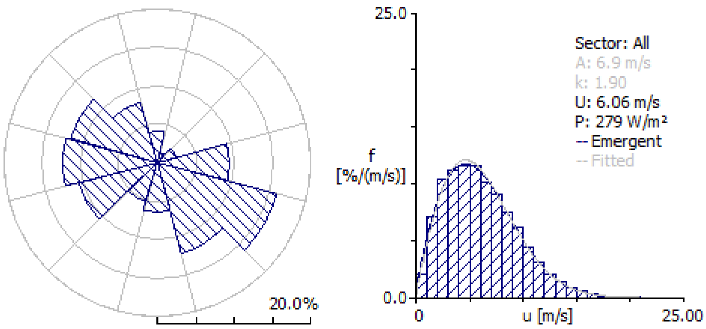

Figure 3. Wind rose and wind speed distribution for a 4-y period at the reference station.

Topographical inputs

The elevation characteristics of the wind farm site and surrounding area are given in a digital terrain model (DTM) with a grid spacing of 50 m in both the *X*- and *Y*-directions; coordinate system is an Ordnance Survey Cartesian coordinate system. The Easting [m], Northing [m] and elevation [m] data were provided for an area of 20×20 km^2 around the wind farm.

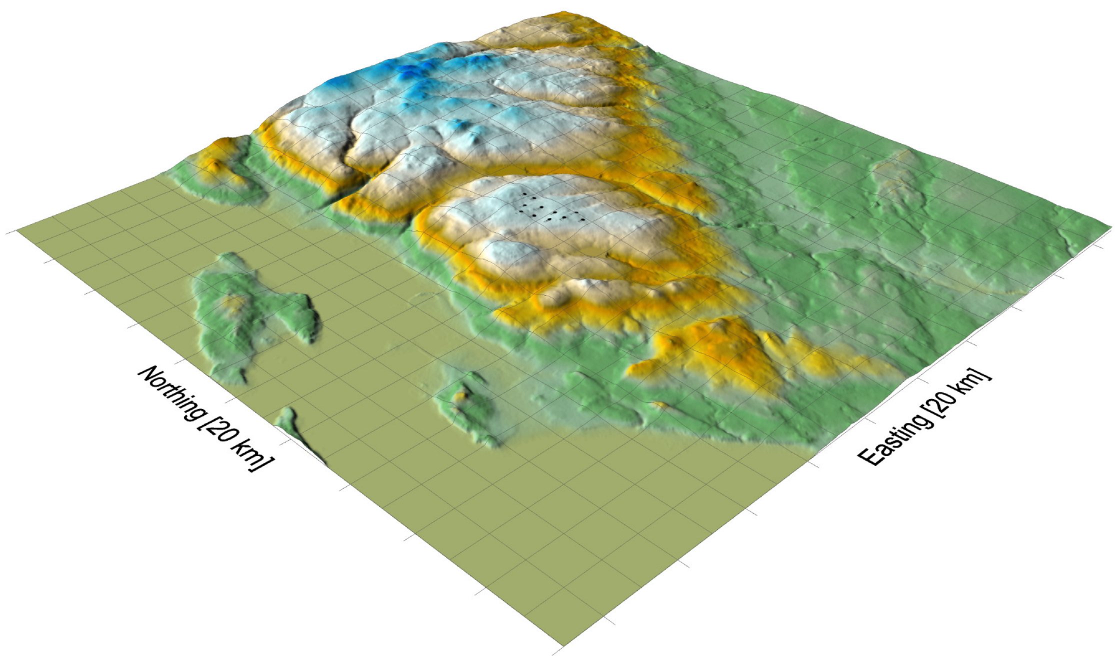

Figure 4. Elevation surface of the wind farm site and surrounding area; covering an area of 20×20 km2. The wind turbine positions are shown as black dots in the centre of the surface graphic.

The estimated elevations of the wind turbine sites are between 343 and 379 meters above sea level (a.s.l.); the ruggedness indices [1, 2] for the sites between 0.7 and 1.9%; both these characteristics were calculated using WAsP 10.1.

For the purpose of the case study, the land cover of the wind farm site and surrounding area is considered uniform and is characterised by an aerodynamic roughness length of 0.03 metres.

3 Data analysis

The data material consists of results spreadsheets received from 40 participants. Submission of results was done through EWEA so the identity of each participant is not known to the authors. Additional questions were mailed through EWEA to nine participants in order to clarify certain results. The case study data pack contains the following description of the required results:

The following model outputs shall be estimated and reported in the model output report template file "Results.xls" (fill in cells coloured in yellow with modelling results):

1.1. The long-term predicted wind speed frequency distribution of hours per year as a function of wind speed and direction. This should be reported at the top anemometer height of 49.6m as well as the turbine hub height of 60m. For convenience of comparison this table should be presented at wind speed bins of 0.5m/s, 1.5m/s etc up to 49.5m/s (data valid at centre of bins) and wind direction bins of 0 degrees, 30 degrees, etc up to 330 degrees relative to OS grid North (data valid at centre of bins). The estimated mean turbulence intensities at 49.6m and 60m need to be provided as well.

1.2. The long-term predicted energy yield of the wind farm project and details of the calculation. This includes:

   a. Reference (or ideal) yield in GWh/year, before topographic and wake effects and any other losses

   b. The topographic effect, i.e. the % change of energy due to terrain variation

   c. Gross yield in GWh/year, including the topographic effect but before wakes or any other losses

   d. Gross to Net loss factors such as wakes, availabilities, electrical efficiency, turbine performance etc as detailed in the results template, as a % loss of energy

   e. The Net energy yield in GWh/year, which is the long term predicted annual average energy yield at the point of metering

1.3. The estimated uncertainty of the long term (10 year) predicted net energy yield, including a breakdown of the individual uncertainty components that have been estimated or assumed.

1.4. A breakdown of the individual contribution of each turbine to the predicted energy yield of the wind farm, as a % of the total production as well as modelled wake and topographic effects per turbine.

Details of how the results have been derived, in particular on how the wind speed prediction has been carried out (e.g. MCP and what technique), if measured or modelled wind shear was used, details of the flow model, details of the wake model (which wake model, details of wake combination, wake meandering, wake added turbulence), etc.

Subsequent data analysis consisted of simple reformatting and quality control of the data received, in order to make sure that results are not biased because of different conventions, formats, etc. Whenever possible, missing results have been calculated from the submitted results, in order to get as many valid results as possible in each category. A comprehensive reanalysis of the submitted results have not been carried out.

For comparable numerical results, the overall distribution of these is described by a normal distribution fitted to the results and standard statistics have been calculated: mean value, standard deviation, variation coefficient, and range.

4 Results

In order to systematically compare the results of the different participants and to compare the methods and/or models employed, we divide the energy yield prediction process into eight steps (where AEP is short for annual energy production):

0. **Observed wind @ 50 m** = statistics of wind measurements @ 50 m
   - No comparison of methods possible
1. **Long-term wind @ 50 m** = [Observed wind @ 50 m] ± [LT correlation effects]
   - Comparison of long-term correlation methods
2. **Long-term wind @ 60 m** = [Long-term wind @ 50 m] ± [wind profile effects]
   - Comparison of vertical extrapolation methods
3. **Reference AEP** = [Long-term wind @ 60 m] combined with the power curve
   - No comparison of methods possible
4. **Gross AEP** = [Reference AEP] ± [terrain effects]
   - Comparison of flow models
5. **Potential AEP** = [Gross AEP] – [wake losses]
   - Comparison of wake models
6. **Net AEP (P50)** = [Potential AEP] – [technical losses]
   - Comparison of technical losses estimates
7. **Net AEP (P90)** = [Net AEP (P50)] – 1.282×[uncertainty estimate]
   - Comparison of uncertainty estimates

Each step is associated with one or more specific models or procedures, in order to derive at the result listed with each step. The different steps in the process are described in more detail below, but detailed comparisons of the different procedures and models are reported elsewhere. Calculation of the mean wind speed (step 0) and reference AEP (step 3) cannot be compared directly, but are assumed to add little to the spread of the results.

Step 0: Observed wind @ 50 m

The observed wind climate at the height of the top anemometer on the site mast consists of the statistics of the wind speed and direction measurements, e.g. the sector-wise wind speed distributions and the wind rose. The participants were not asked to report these statistics nor the method (or software) used to derive them, so no comparison of procedures or methods is therefore possible.

Step 1: Long-term wind @ 50 m

The long-term (LT) wind climate at the height of the top anemometer consists of similar statistics as described for Step 0, but referenced to a long-term period, in this case 14 years. The methods employed by the participants are MCP (matrix method, hourly values, monthly means), correlation with NWP or reanalysis data (2), NOAA-GSOD index (1), none (3). Three participants chose not to apply any long-term correlation procedure at all. The detailed comparison of long-term correlation methods will be reported elsewhere.

Step 2: Long-term wind @ 60 m

The long-term (LT) wind climate at hub height consists of similar statistics as described above, but referenced to hub height at the mast site. The vertical extrapolation methods employed are: Observed power law/log law profile (21), WAsP (12), WindSim (2), unspecified CFD (2), and NWP (1). The detailed comparison of vertical extrapolation methods will be reported elsewhere.

Step 3: Reference energy yield

The wind farm reference energy yield is defined here as the yield of a single turbine erected at the site of the meteorological mast, times the number of turbines in the wind farm. It is calculated from the wind distributions at hub height and the wind turbine power curve. No comparison of methods is possible.

Step 4: Gross energy yield

The flow models used to calculate the topographical effects and the wind farm gross energy yield are: WAsP (26), MS3DJH (2), WindSim (2), unspecified CFD (2), NWP (1), MS-Micro/3 (1), other (1). The detailed comparison of wind flow models will be reported elsewhere.

Step 5: Potential energy yield

The potential energy yield is defined here as the gross energy yield minus the wind farm wake losses. The wake models used to calculate the wind farm wake effects and potential energy yield are: WAsP PARK (19), WindPRO PARK (8), WindFarmer Eddy Viscosity (5), Ainslie Eddy Viscosity (3), EWTS II (2), CFD Actuator (1), FLaP (1), and Confidential (1). The detailed comparison of wake models will be reported elsewhere.

Step 6: Net energy yield P_{50}

The losses estimates used to calculate the P_{50} net energy yield were based on given categories of availability and technical losses. Losses associated with availability are: turbine availability (10 year), balance of plant availability, grid availability and other availability. Technical losses are listed as: electrical transmission loss, power curve performance, high-wind-speed hysteresis loss, other turbine performance (high turbulence etc.), blade degradation and other losses. The detailed comparison of technical losses estimates will be reported elsewhere.

Step 7: Net energy yield P_{90}

Unlike the losses estimates, uncertainty estimates used to calculate the P_{90} net energy yield were not based on fixed categories, but left for the participants to classify. The detailed comparison of uncertainty estimates will be reported elsewhere.

Summary of results

Table 1 summarises the overall results of the wind climate estimations at the site mast. The spread of predictions is given as their standard deviation and as their coefficient of variation (CV, defined as the ratio of the standard deviation to the mean).

Table 1. Summary of wind statistics for the first three steps in the prediction process. Column 'σ' is the standard deviation; 'CV [%]' is the coefficient of variation, and Min. and Max. are the minimum and maximum values of the results, respectively. LT is short for 'long-term'.

Prediction step/process	Unit	Mean	σ	CV [%]	Min.	Max.
Observed wind @ 50 m	ms^{-1}	8.47	0.02	0.2	8.45	8.48
LT correlation effects	%	1.8	2.5	138	−2.4	10.6
LT wind @ 50 m	ms^{-1}	8.66	0.21	2.4	8.31	9.41
Shear exponent		0.167	0.037	22	0.015	0.237
LT wind @ 60 m	ms^{-1}	8.94	0.22	2.5	8.58	9.70

Table 2 summarises the overall results of the energy yield estimations of the wind farm.

Table 2. Summary energy yield statistics for the last five steps in the prediction process. Column 'σ' is the standard deviation; 'CV [%]' is the coefficient of variation, and Min. and Max. are the minimum and maximum values of the results, respectively.

Prediction step/process	Unit	Mean	σ	CV [%]	Min.	Max.
Reference yield	GWh	116	7.4	6.4	98	131
Topographic effects	%	4.9	7.2	146	−6.0	22
Gross energy yield	GWh	121	3.4	2.8	113	127
Wake effects	%	6.1	0.8	13	4.5	8.1
Potential yield	GWh	113	3.5	3.1	104	120
Technical losses	%	9.2	2.9	32	5	20
Net energy yield P_{50}	GWh	103	4.5	4.4	91	113
Uncertainty estimate	%	11	3.6	32	6	21
Net energy yield P_{90}	GWh	89	6.2	6.9	73	99

The end result for the wind farm net production is thus **P_{90} = 89 GWh/y** and **σ_P = 7%**, with a range of results from 73 to 99 GWh/y (29%).

Figure 5 shows the coefficient of variation for seven steps in the prediction process, corresponding to the column 'CV' in Table 1 and Table 2.

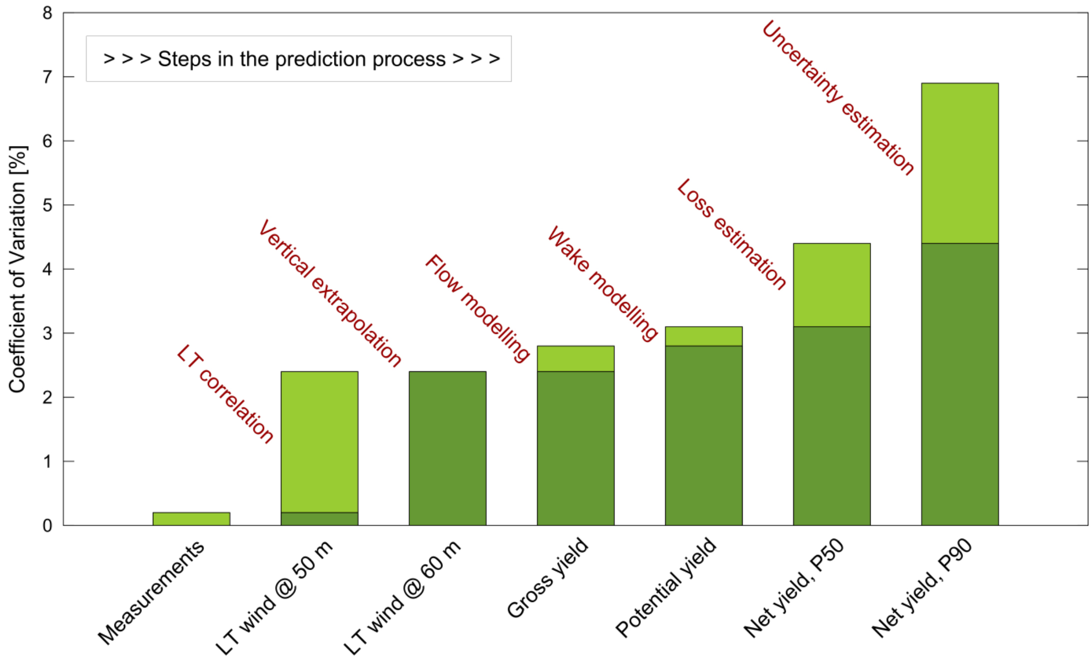

Figure 5. Variation coefficient for seven different steps in the wind resource and energy yield prediction process. The light green part of each bar corresponds to the contribution from each step. LT is short for 'long-term'.

Figure 6 shows the distributions of the different energy yield estimates for the case study wind farm. The distributions are given as standard box-whisker plots [3], showing the smallest observation, lower quartile (Q1), median (Q2), upper quartile (Q3), and largest observation.

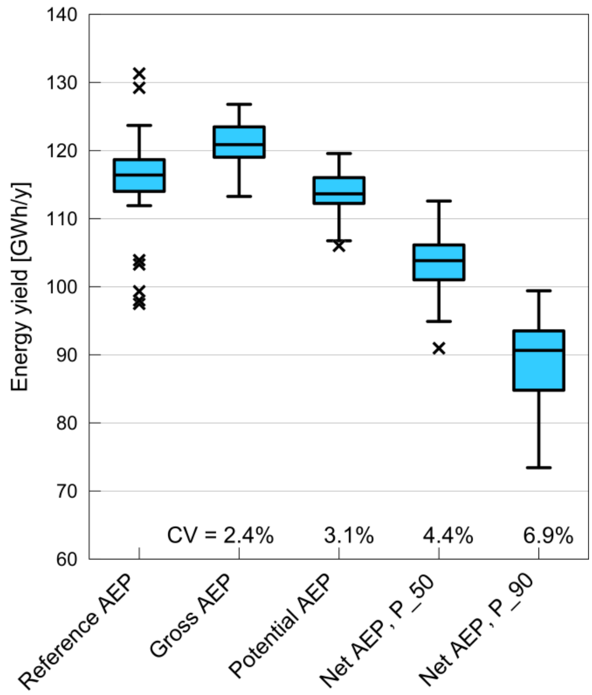

Figure 6. Distribution of predicted energy yields of the case study wind farm. The coefficient of variation is given for each step shown.

The whiskers represent here the lowest datum still within 1.5 IQR (the interquartile range Q3-Q1) of the lower quartile, and the highest datum still within 1.5 IQR of the upper quartile.

5 Discussion and conclusions

In the present case study, three steps add little to the overall spread of predictions: the vertical extrapolation (contributes about 0%), the flow modelling (6%) and the wake modelling (5%). This is not surprising considering the limited vertical extrapolation distance (10 m), the presence of an on-site meteorological mast and the rather simple wind farm layout.

Three steps add significantly to the overall spread of predictions: the long-term correlation (32%), the technical losses estimation (20%) and the uncertainty estimation (38%). Here, the contribution from the long-term correlation seems particularly high considering the fact that all participants had the exact same two data sets available for estimation of the long-term correlation effects.

The comparison exercise further reveals that the definition and usage of concepts and terms in the industry are ambiguous; e.g. the term 'reference yield' is not understood in the same way by different participants. Likewise, the engineering practices and ways of reporting are quite different, making detailed comparisons of certain steps difficult.

Comparison exercises (or verification data sets in public domain) can help improve the wind energy industry's procedures, best practices and standards. Future comparisons could address sites with significant roughness effects and roughness changes, vertical extrapolation effects, atmospheric stability effects (coastal site); or, wind farm sites located offshore, in forested or in complex terrain.

The present paper summarises the main results of the comparison exercise only; the detailed analysis of the specific methods, models and procedures employed by the participants will be published elsewhere.

Acknowledgements

The data pack used for the comparison was made available by Renewable Energy Systems Ltd. (RES); thanks in particular to Gerd Habenicht, Mike Anderson and Karen-Anne Hutton for preparing the data pack.

The original 37 sets of results reported here were submitted by 35 organisations from 16 countries for the EWEA Wind Resource Assessment Workshop in 2011; thanks to all of the participants for making the comparison possible. More information is available at www.ewea.org.

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